A Spreadsheet Approach to Diverter Design Calculations

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ABSTRACT

Diverter Systems must be designed to provide back pressures which will not result in fracture at the conductor casing seat. The system design loads are generally based on a shallow gas flow encountered prior to setting surface casing. Calculation of the pressure at various points in a diverter system is complicated by sonic flow at the exit, by unusually rapid fluid acceleration in some parts of the system, by temperature changes, and by the possible presence of more than one phase. A recent paper presented at the European Well Control Conference (Bourgoyne, 1992) presented a new empirical correlation for predicting sonic exit pressures during multi-phase flow. This correlation was based on experimental data carried out in 8 inch (0.203 m) and 10 inch (0.254 m) model diverter systems. The practical use of the calculation methods presented in this previous paper is now illustrated using a spreadsheet approach.

INTRODUCTION

A key element of shallow gas well control is the selection of appropriate conductor casing setting depth that works well with the rig diverter system for the maximum likely formation pressure and productivity in the area of interest. Beck, Langlinais, and Bourgoyne (1987) recommended that the diverter and casing should be designed using a systems analysis approach that considers the gas reservoir, borehole, casing, and diverter linked together as a single hydraulic system. A systems analysis procedure (Brown and Beggs,(1977), Crouch and Pack, (1980), and Clark and Perkins, (1980) permits the simultaneous calculation of steady state pressures throughout the well and diverter system. A similar approach was recently presented in detail in API RP 64 (1991).

One of the problems encountered when using a systems analysis procedure is the need for an accurate prediction of the pressures occurring in the diverter system at potentially high gas flow rates. Calculation of the pressure at various points in a diverter system is complicated by sonic flow at the exit, by unusually rapid fluid acceleration in some parts of the system, by temperature changes, and by the possible presence of more than one phase. Conventional equations and computer algorithms used by petroleum engineers to analyze producing wells cannot be applied with any confidence. Recently, experiments involving two-phase (gas-water) flow were carried out in 8 inch (0.203 m) and 10 inch (0.254 m) model diverter systems at rates sufficient to achieve sonic flow (Bourgoyne, 1992). An improved algorithm for calculating pressures and fluid velocities at various points in a diverter system was developed based on this experimental study.

RECOMMENDED ALGORITHM

The recommended diverter design calculations require the use of equations describing (1) sonic exit pressure, (2) flowing pressure gradients in the diverter and well, (3) formation productivity, (4) formation fracture gradient, and (5) erosion.

Sonic Exit Conditions

The limiting (sonic) velocity at the vent line exit, v_e, can be computed for any fluid using

$$v_e = \frac{1}{\sqrt{\rho c}} \tag{1}$$

where r is the density of the fluid, and c is the compressibility of the fluid. For liquids, the density, ρ, and compressibility, c, can be assumed constant and are easily defined. For gases, the density can be determined from the real-gas equation, and is given by

$$\rho_g = \frac{p\bar{M}}{zRT} \tag{2}$$

for any given pressure, p, gas molecular weight, M, gas deviation factor, z, and temperature, T, at the diverter exit. The coefficient, R, is the universal gas constant for the system of units being used. For most accurate results, the gas compressibility at the exit should be computed assuming a polytropic process. This assumption gives

$$c_g = \frac{1}{np} \tag{3}$$

where n is the polytropic expansion coefficient for the process. For an adiabatic expansion of an ideal gas, n becomes equal to the ratio, k, of specific heat at constant pressure, Cp, to specific heat at constant volume, C_V. For sonic gas flow through a restriction, k is often used as an approximate value for n.

When the fluid being produced from the well is a multi-phase mixture rather than single phase gas, Eqn. 1 can still be applied through use of appropriate values for effective density, effective compressibility, and effective polytropic expansion coefficient, n. It is recommended that the effective multi-phase density, ρ_e, is calculated using

$$\rho_e = \rho_g H_g + \rho_l H_l + \rho_s H_s \tag{4}$$

where H denotes the volume fraction (hold-up), and subscripts g, l, and s denotes the gas, liquid, and solid phases present. For sonic flow, the slip velocity between the phases can be neglected when calculating the volume fractions. Wallis (1969) recommended calculating an effective compressibility, c_e, in a similar manner using

$$c_e = c_g H_g + c_l H_l + c_s H_s \tag{5}$$

Ross (1960) had previously used this approach, but for simplicity, he considered the second and third terms of this equation to be negligible. Bourgoyne (1992) found that the effective value of n varied with gas weight percentage (quality), χ_g. For the range of conditions studied, n could be approximately defined by

$$n = k - 2\text{Log}_{10}(\chi_g) \tag{6}$$

<u>Flowing Pressure Gradient</u>

Upstream of the vent line exit, the pressure gradient, dp/dL, is given by the expression

$$\frac{dP}{dL} = \bar{\rho} g \cos(\theta) + \frac{f \bar{\rho} \bar{v}^2}{2d} + \frac{\rho \Delta \bar{v}^2}{2\Delta L} \tag{7}$$

where the first term accounts for hydrostatic pressure changes, the second term accounts for frictional pressure losses, and the third term accounts for pressure changes caused by fluid acceleration. In the first term, g represents the acceleration of gravity and θ represents the vertical deviation angle of the flow section under consideration. The Moody (1944) friction factor, f, in the second term is given by

$$\frac{1}{\sqrt{f}} = -2\text{Log}_{10}\left(0.27\frac{e}{d} + \frac{2.52}{N_{Re}\sqrt{f}}\right) \tag{8}$$

where e is the absolute roughness and d is the pipe diameter. A value of 16.5 μm (0.00065 in.) for roughness was found to yield good agreement with experimental data obtained in pipe having a diameter of 0.1244 m (4.9 in.). The Reynolds number, N_{Re}, is defined by

$$N_{Re} = \frac{\rho \bar{v} d}{\mu} \tag{9}$$

where v is the average fluid velocity and μ is the fluid viscosity.

At a sudden decrease in the area of the flow path, such as at the vent line entrance, the pressure drop due to fluid acceleration, Δpa, can be estimated using

$$\Delta p_a = \rho \frac{\Delta \bar{v}^2}{2} \tag{10}$$

However, the downstream velocity cannot exceed the sonic velocity predicted by Eqn. 1. When sonic velocity occurs, the downstream pressure will be governed by Eqn. 1.

At a sudden increase in the area of the flow path, such as at the casing seat and at the top of the drill collars, the increase in pressure due to fluid deceleration is generally small and can be neglected. Since there is no diffuser present that can provide a smooth transition to the larger flow area, almost all of the theoretical pressure recovery predicted by Eqn. (10) is lost to turbulence.

When the fluid being produced from the well is a multi-phase mixture, Eqns. 8 - 10 can be applied through use of appropriate values for effective density, effective viscosity, and effective velocity. For high flow rates typical of shallow gas flows, the effective multi-phase density, ρ_e, viscosity, μ_e, and velocity, v_e, can be calculated assuming no slippage between the phases. Thus, the effective multi-phase density, ρ_e, is given by Eqn. 4, and effective multi-phase viscosity, μ_e, is given by

$$\mu_e = H_g \mu_g + H_{ls} \mu_{ls} \qquad (11)$$

where the subscript 'ls' refers to a liquid-solids slurry mixture and thus includes the effect of any solids present by including them in the liquid phase. The effective multi-phase velocity, v_e, is defined in terms of flow rate, q, and cross sectional area, A, by

$$v_e = \frac{q_g + q_l + q_s}{A} \qquad (12)$$

Experiments conducted in model diverter systems (Bourgoyne, 1992) have indicated that significant cooling of the flow stream occurs due to gas expansion. It is recommended that if a software package for calculating heat-loss is not available, adiabatic flow should be assumed rather than isothermal flow. For adiabatic flow, temperature changes between points can be computed using

$$\Delta T = \frac{\Delta \bar{v}^2}{2(\chi_g C_{pg} + \chi_l C_{pl} + \chi_s C_{ps})} \qquad (13)$$

Convenient distance step sizes can be assumed when using the pressure gradient to move upstream in a stepwise manner. It is often convenient to choose a step size that will end on a fitting boundary when a diameter change or bend occurs.

Formation Productivity

Resistance to flow is present in the gas reservoir as well as in the flow path to the surface. Since little is generally known about the properties of the gas reservoir causing the unexpected flow, detailed reservoir simulations are not usually justified. However, it is important to take into account turbulence and other factors that become important at high gas velocities. The Forchheimer (1901) equation as adapted for horizontal, radial, semi-steady state flow in a homogeneous gas reservoir is recommended for use in design calculations for diverter systems. This equation can be arranged to give flowing bottom-hole pressure, p_{bh}, within a wellbore of radius, r_w, due to flow within a horizontal, circular reservoir of external radius, r_e, effective thickness, h, penetrated thickness, h_p, and having an average reservoir pressure, p_r. The Forchheimer equation for these conditions is defined by

$$p_{bh}^2 = p_r^2 - [\frac{\mu T z p_{sc}}{\pi T_{sc} kh} \ln_e(0.472\frac{r_e}{r_w})] q_{sc} - [\frac{\beta z M T p_{sc}^2}{2R\pi^2 T_{sc}^2 h_p^2}(\frac{1}{r_w} - \frac{1}{r_e})] q_{sc}^2 \qquad (14)$$

where the subscript 'sc' denotes standard conditions. The terms in brackets reduce to a constant for a given reservoir. The second term is needed to properly model high- velocity gas flow where the velocity coefficient, b, is determined empirically. Note that once the bracketed terms are reduced to a constant, a relatively simple relationship between gas flow rate and flowing bottom-hole pressure results.

Laboratory core data shows that the velocity coefficient, b, tends to decrease with increasing permeability. Since shallow sands tend to be unconsolidated, a correlation based on data taken in unconsolidated samples (Johnson and Taliaferro, 1938) is recommended for diverter system design calculations. The recommended correlation gives β in m^{-1} using

$$\beta = \frac{1.031}{\sqrt{k}} \tag{15}$$

where the permeability, k, is given in m^2.

Choosing a representative value for the reservoir thickness, h, is complicated by the fact that the wellbore often penetrates through only part of the gas reservoir before the shallow gas flow is detected and drilling is stopped. When this is true, the gas flow is not radial as assumed by Eqn. 14, and an effective thickness value must be used. This effective thickness depends on the ratio of the horizontal to vertical permeability, the wellbore radius, r_w, the total formation thickness, h_f, and the formation thickness penetrated by the bit, hp. When the vertical permeability is much less than the horizontal permeability, the effective thickness is approximately equal to the thickness penetrated by the bit. As the vertical permeability increases and approaches the horizontal permeability, the following equation presented by Craft and Hawkins (1959) can be used to estimate the effective thickness for use in the first term of Eqn 14:

$$h = h_p[1 + 7\sqrt{\frac{r_w}{2h_p}}\cos(\frac{\pi}{2}\frac{h_p}{h_f})] \tag{16}$$

The thickness penetrated by the bit is always used for the second term in Eqn 14 because non-darcy flow is generally limited to a region very close to the borehole.

Formation Fracture Pressure

Constant and Bourgoyne (1989) have recommended fracture pressure equations for offshore drilling operations based on Eaton's correlation. The recommended method gives the absolute overburden stress, σ_{ob}, in SI units (kPa) in terms of the sea water depth, Dsw, and the sediment depth below the seafloor, Ds, (both in meters) using

$$\sigma_{ob} = 101.3 + 10D_{sw} + 25.5D_s - 21980[1 - \exp(-0.000279D_s)] \tag{17}$$

The minimum expected absolute formation fracture pressure, p_f, is then determined from the absolute formation pore pressure, p_p, and the overburden pressure, σ_{ob}, by

$$p_f = p_p + [1 - 0.629\exp(-0.00042D_s)][\sigma_{ob} - p_p] \tag{18}$$

This minimum fracture pressure would correspond to extending an existing fracture in a sandy formation. Higher formation fracture pressures would be expected for fracture initiation and in plastic "gumbo" shale formations. The maximum expected pressure for fracture extension is the overburden pressure given by Eqn 17.

Erosion

Based on the experimental work performed Bourgoyne (1989) proposed the following equation in SI units for estimating the rate of loss in wall thickness, h_w, with time, t, in a diverter bend.

$$\frac{dh_w}{dt} = F_e \frac{\rho_a}{\rho_s}\frac{q_a}{A}(\frac{q_g}{100AH_g})^2 \tag{19}$$

This equation assumes the diverter bend is made of steel with density, ρ_s, and flow cross sectional area , A, flowing abrasives having density, ρ_a, at a volumetric flow rate, q_a, and flowing gas at a volumetric flow rate, q_g, and gas volume fraction (holdup) Hg. Recommended values for specific erosion factor, Fe, are given in Table 1. Some of these recommended values have been modified slightly since 1989 after making additional erosion tests in fittings of larger diameter. The accuracy of the proposed calculation method was verified using the experimental data collected. The average error observed was 29 percent. This level of accuracy was felt to be acceptable for diverter design considerations. Relatively large error ranges are often associated with the use of an empirical correlation for describing multi-phase flow phenomena.

Diverter Anchors

Some diverter failures have involved the anchor system used to hold the vent line piping in place. The anchor system should be carefully designed to withstand the forces resulting from the moving fluids. The maximum forces on the anchoring system occurs when the wellhead pressure reaches its peak value. When telescoping segments or slip joints are used below the annular blowout preventer, a maximum upward force on the wellhead that is equal to the peak pressure multiplied by the internal annular cross sectional area at the slip joint must be resisted. In computer simulations made by Santos (1989), these forces sometimes reached as high as 1.3 MN (300,000 lbf) for the field conditions studied. Similarly, a maximum axial thrust distributed along the length of the vent line exists which is equal to the peak pressure multiplied by the internal cross sectional area of the vent line. In addition, at bends in the diverter system, the anchor system must resist a force equal to the mass rate of flow multiplied by the change in the fluid velocity vector at the bend. For a 90-degree bend, this force is approximately given by the fluid density times the square of the average velocity, ρv^2.

SPREADSHEET APPROACH

It was found that the system of equations described above could be conveniently programmed using a modern spreadsheet program. This approach was found to minimize the programming time required but yet retain considerable flexibility with respect to modifying the program to handle unusual well or diverter configurations. It also provides easy access to the powerful graphical packages available on modern spreadsheets and allows the results to be easily transported to a word processor program. An example is given here to demonstrate this approach and to provide the reader with a solved example for checking similar programs that they develop.

Example

An example incident that occurred on a Jack-up type rig in the Gulf of Mexico (offshore Texas) in 1975 illustrates the need for a more complete analysis of diverter system operating conditions. Two 0.152-m (6-in.) diverter vent lines were attached to 0.762-m (30-in.) casing, which was set at 149 m (490 ft), and penetrated 58 m (190 ft) of sediments. A 0.251-m (9.875-in.) pilot hole was drilled to 351 m (1,150 ft). The well plan called for enlargement of the hole to 0.508 m (20 in.) prior to setting conductor casing. However, a gas flow was encountered after pulling two stands of the drill-string out of the hole. The diverter system was actuated and both diverter vent lines were opened. Both mud pumps were used to circulate fluid into the well as fast as possible in an attempt to regain control. The rig began to list slightly and was evacuated. Within the next 12 hours, the rig turned over and sank into a subsea crater. The well stopped flowing after six days, and was thought to have bridged.

The use of Eqns. 1 - 19 for estimating the flowing pressures at various points in the system are illustrated in Tables 2-5 for an assumed horizontal diverter length of 30 m (98 ft). The vent line is assumed to have one long-radius bend (r/d=3) at a distance of 25.46 m (83.5 ft) from the exit. Tables 2 and 3 are for a diverter diameter of 0.152 m (6 in.), which was commonly used during the 1970's. Table 4 and 5 are for a diverter diameter of 0.254 m (10 in.), which is more representative of current practice. The 0.762-m (30-in.) casing that was set at 149 m (490 ft) was assumed to have a 2.54-cm (1-in.) wall thickness. The drill string was composed of 224 m (735 ft) of drillpipe having an outer diameter of 12.7 cm (5 in.) and 100 m (328 ft) of drill collars having an outer diameter of 19.1 cm (7.5 in.). Beneath the bit was 27 m (89 ft) of open borehole having a diameter of 25.1 cm (9.875-in.). The projected area of the bit that partly blocked the annular flow path was equivalent to a diameter of 22.2 cm (8.74 in.).

The parameters shown in single-line boxes on the example spreadsheets are the required input data to define the problem. All other cells are computed from this input data. The parameters in the double-line box in the lower right-hand corner of page 2 of the spreadsheet are automatically calculated using the input value of formation pressure and the fracture gradient correlation defined by Eqn 18. However, these default values can be replaced by entering new cell values for pore pressure and fracture pressure from the keyboard. A solution is found when the flowing bottom hole pressure at the formation face calculated from Eqn 14 (Column 11 at the bottom of page one of the spreadsheet) is equal to the flowing bottom hole pressure calculated from flow-string resistance (Column 3 at the bottom of Page 2 of the spreadsheet). The solution is obtained by guessing values of Diverter Exit Pressure (Column 1 at the bottom of Page 1 of the spreadsheet). The solution can be found automatically using the "Goal-Seeking" option of a modern spreadsheet. The gas Z-factors and viscosity were obtained in the example spreadsheet using algorithms developed for the Petroleum Pac on an HP41-CV calculator.

Note that for the 0.152-m (6-in.) vent line, the expected fracture pressure at the casing seat would be exceeded, whereas for the 0.254-m (10-in.) vent line, a 953 kPa (138 psi) safety margin would exist. If only a 0.152-m (6-in.) diverter system were available, an acceptable design for this well may still have been possible using a longer conductor casing. Erosion due to sand production for the input sand concentration of 0.02 weight fraction

(1100 lb.MMscf) would cut through the long radius bend after 23 min for the 0.152-m (6-in.) vent line and after 42 min for the 0.254-m (10-in.) vent line. Erosion life could be increased an order of magnitude by using a plugged tee or vortice elbow in place of the long radius elbow.

When the shallow gas contingency plan calls for using two diverter lines of equal diameter in parallel, half of the total flow will exit through each of the vent lines. This situation is easily handled in the analysis procedure illustrated above by using half of the total gas flow rate in the surface vent line section of the spreadsheet. The total gas flow rate must be used for the annulus and borehole sections.

Working Pressure of Diverter Components

The systems analysis procedure shown in the example spreadsheets provides information about the pressures that could be expected on the diverter system components after the well is unloaded and pseudo-steady-state conditions are reached. However, while the drilling fluid is being displaced from the well, the mud in the system behaves as a viscous plug which greatly slows flow through the diverter. This situation results in a pressure peak occurring when the leading edge of the gas reaches the vent line entrance. The magnitude of the pressure peak depends primarily on the formation pressure and on the amount of mud that remains in the well due to slippage past the gas while the well is unloading. The pressure peak can be substantially higher than the equilibrium wellhead pressure calculated from a systems analysis procedure. This pressure peak is of short duration, typically lasting only a few seconds. If fracturing occurs, it is unlikely that fracture propagation would move very far from the wellbore before the pressure subsides to the equilibrium value. As long as the equilibrium borehole pressure is less than the fracture extension pressure, there is a high probability that the fracture will not propagate to the surface. It is recommended, therefore, that the design load at the casing seat is based on equilibrium flowing conditions. However, the design load for surface diverter system components should be based on the pressure peak occurring when the drilling fluid is being displaced from the well.

Santos (1989) performed experiments on a 0.152-m (6-in.) diverter vent line attached to a 382 m (1252 ft) well containing 0.178-m (7-in.) casing to study unsteady-state pressure behavior when the well is first placed on a diverter system. In the experiments, the gas entering the bottom of the well flowed through a valve that was controlled by a process control computer that simulated the behavior of a formation. A program was developed for the flow control computer to permit a range of formation productivity to be simulated. Pressures were monitored during the experiments at a number of locations in the well and diverter. Experimental runs were made using a number of different mud systems.

Santos (1989) developed a computer model for predicting the pressures and flow rates observed during a shallow gas flow as a function of both time and position. The program was first verified using the experimental results obtained with the model diverter system. The computed results for peak wellhead pressure matched the observed pressure peaks within an error band of about 25 percent. The program was then used to simulate a wide variety of field conditions. It was found that the peak wellhead pressure tended to decrease with decreasing formation pressure, decreasing formation productivity, and increasing vent line diameter. For the field conditions studied, the peak wellhead pressure was generally less than 65 percent of the formation pressure. Also, the time required to unload the well was typically only a few minutes.

The Santos computer model was run for the 0.254-m (10-in.) diverter vent line discussed in the previous example calculations. The drilling fluid in the well when the shallow gas flow began was assumed to have a density of 1116 kg/m^3 (9.3 lb/gal). This program predicted that the well would unload in about one minute with a peak wellhead pressure of 1.436 MPa (208 psi), which was about 34 percent of the formation pressure. Thus, a working pressure for diverter components of at least this value would be needed. The calculated pressure at the casing seat exceeds the minimum fracture extension pressure of 1.467 MPa (214 psi) during most of the first minute but drops to about 496 kPa (72 psi) after pseudo-steady state conditions are reached. Similar simulations performed for a 0.152-m (6-in.) diverter vent line gave a peak wellhead pressure of 2.620 MPa (380 psi), which was about 63 percent of the formation pressure. These calculations indicate that smaller vent lines should have a higher working pressure. For 10-in. vent lines, a working pressure of half the formation pore pressure seen just prior to setting surface casing appears to be a reasonable rule-of-thumb.

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NOMENCLATURE

A	Cross sectional area, m^2.
c	Compressibility, Pa-1.
C_p	Heat capacity at constant pressure, J/kg/oK.
C_v	Heat capacity at constant volume, J/Kg/oK.
D	Depth.
d	Diameter, m.
e	Roughness, m.
f	Moody friction factor.
g	Acceleration due to gravity.
H	Hold-up (volume fraction).
h	Thickness.
k	Ratio of heat capacity at constant pressure to heat capacity at constant volume. Also permeability, m^2.
L	Length.
M	Molecular weight.
N_{Re}	Reynolds Number.
n	Polytropic expansion coefficient.
p	Pressure, Pa. Also psia in Equation (A-6).
q	Volumetric flow rate, m3/s.
r	Radius, m
R	Universal gas constant .
T	Temperature, oK.

z	Gas deviation factor.
v	Velocity, m/s.
β	Non-darcy coefficient, m^{-1}.
Δ	Delta operator (difference).
χ	Weight fraction or quality.
μ	Viscosity, Pa-S.
σ_{ob}	Overburden stress.
θ	Vertical deviation angle, rad.
ρ	Density, kg/m3.

Supscripts:

a	Abrasive (sand). Also acceleration.
bh	Bottom-hole.
e	Effective. Also external.
f	Formation.
g	Gas.
l	Liquid.
ls	Liquid-Solid Mixture.
p	Penetrated. Also pore.
r	Reservoir.
s	Steel. Also sediments penetrated.
sc	Standard conditions.
sw	Sea water.
w	Well.

Fitting Type	Curvature Radius (r/d)	Material	Grade	Specific Erosion Factor, F_e (g/kg)
Elbow	1.0	Seamless Steel	WPB	2.0
	1.5	Seamless Steel	WPB	1.7
	2.0	Seamless Steel	WPB	0.93
	2.5	Seamless Steel	WPB	0.77
	3.0	Seamless Steel	WPB	0.66
	4.0	Seamless Steel	WPB	0.49
	5.0	Seamless Steel	WPB	0.38
Flexible Hose	6.0	Rubber	—	1.2
	8.0	Rubber	—	0.45
	10.0	Rubber	—	0.39
	12.0	Rubber	—	0.35
	15.0	Rubber	—	0.31
	20.0	Rubber	—	0.28
Plugged Tee		Seamless Steel	WPB	0.064
Vortice Elbow	3.0	Cast Steel	WPC	0.0078*

** Failure in pipe wall downstream of bend.*

Table 1 - Recommended Specific Erosion Factors (grams removed per kilogram of sand)

Table 2 -- Page 1 of Example Spreadsheet for 6-in. diameter Diverter

WELL CONDITIONS OF CALCULATION:

Diameter	0.153	m	6.004	in.
Pipe Roughness	1.7E-5	m	6.5E-4	in.
Base Pressure	101.3	kPa	14.69	psi
Base Temperature	15	Deg C	59	Deg F
Exit Temperature	-5	Deg C	23	Deg F
Liquid Content	0.1	Wt Frac	15	Bbl/MMscf
Density of Liquids	1060	kg/m3	8.85	lb/gal
Liquid Compressibility	4.7E-7	kPa-1	3.3E-6	psi-1
Liquid Heat Capacity	4.2	kJ/kg/Deg K	1.00	btu/lb/Deg R
Solid Content	0.02	Wt Frac	1112	lb/MMscf
Density of Solids	2630	kg/m3	21.95	lb/gal
Solid Compressibility	4.0E-8	kPa-1	2.8E-7	psi-1
Solid Heat Capacity	0.9	kJ/kg/Deg K	0.21	btu/lb/Deg R
Viscosity of Liquid-Solid Mixture	1.0E-3	Pa.s	1.00	cp
Gas Specific Gravity	0.64		0.64	
Heat Capacity Ratio, k	1.31		1.31	
Gas Quality	0.88	Wt Frac	0.88	Wt Frac
M	18.5	kg/mole	18.5	lb/mole
Universal Gas Constant, R	8.31	kJ/kmole/Deg	1.99	btu/mole/Deg R
Gas Constant (mass basis), R'	0.448	kJ/kg/DegK	10.73	psi ft3/Deg R/mole
Cp	2.21	kJ/kg/Deg K	0.53	btu/lb/Deg R
Cv	1.69	kJ/kg/Deg K	0.40	btu/lb/Deg R

FORMATION CHARACTERISTICS:

Formation Pressure	4137	kPa	600	psi
Formation Temp	30	Deg C	86	Deg F
Permeability	1.5E-11	m2	1.5E+4	md
Non-Darcy Beta	3.3E+5	m-1	1.0E+5	ft-1
Skin Factor	0		0	
Reservoir Radius	305	m	1001	ft
Wellbore Radius	0.126	m	0.41	ft
Formation Eff. Thick	3.05	m	10	ft
Formation Depth	351	m	1152	ft
Water Depth	58.0	m	190	ft
Air Gap	33.0	m	108	ft
Porosity Decline Con	2.8E-4	m-1	8.5E-5	ft-1
Specific Erosion Factor	6.6E-4	kg/kg	6.6E-4	lb/lb
Wall Thickness	0.0095	m	0.375	in.
Wall Density	7850	Kg/m3	65.51	lb/gal
Tr at Formation	1.48		1.48	
Pseudo Reduced Densi	0.181		0.18	
Formation Gas z Factor	0.908		0.91	
Formation Gas Density	100	kg/m3	0.83	lb/gal
Formation Gas Viscosit	1.5E-5	Pa.s	0.015	cp

Diverter Exit Calculations

(1) Pres (kPa)	(psi)	Pseudo Reduced Density	(2) z	(3) Gas Den Eqn. 2 (kg/m3)	(4) n Eqn. 6	(5) Cg Eqn. 3 (kPa-1)	(6) Gas Vol Frac	Liquid Vol Frac	Solids Vol Frac	(7) Mix Density Eqn. 4 (kg/m3)	(8) Mix Comp. Eqn. 5 (Pa-1)	(10) Gas Flow Rate at S.C. (m3/s)	(MM/d)	(11) Flowing BH Pressure at formation (kPa)	(psi)
500.1	72.5	0.0228	0.983	4.23	1.42	1.4E-3	0.9995	0.0005	0.0000	4.80	1.4E-3	37.9	115.6	3587	520

Table 3 --Page 2 of Example Spreadsheet for 6-in. Diverter

Flow Path Pressure Drop Calculations

(1) Dist From Exit (m)	Vert Depth (m)	(2) Outer Pipe Diam (m)	Inner Pipe Diam (m)	(3) Pres (kPa)	(4) Temp (oK)	(5) Pseudo Red Den	(6) z	(7) Gas Den Eqn. 2 (kg/m3)	(8) Gas Visc (Pa-s)	(9) Gas Vol Frac	Liq Vol Frac	(10) Mix Den Eqn. 4 (kg/m3)	(11) Mix Vel (m/s)	(12) Mix Visc (Pa-s)	(13) Rey Num	(14) Moody Fric Fac	(15) Hyd dP (kPa)	(16) Fric dP (kPa)	(17) Acc dP (kPa)	(18)	(19)	(20)
0	0	0.1525	0	500.1	268	0.0228	0.983	4.23	1.0E-5	0.9995	0.0005	4.80	384.7	1.0E-5	2.7E+7	0.0122	0	14	0			
0.5	0	0.1525	0	514.4	268	0.0234	0.983	4.35	1.0E-5	0.9995	0.0005	4.94	373.9	1.0E-5	2.7E+7	0.0122	0	14	20			
1	0	0.1525	0	548.5	270	0.0249	0.982	4.62	1.0E-5	0.9995	0.0005	5.24	352.6	1.1E-5	2.7E+7	0.0122	0	26	41			
2	0	0.1525	0	615.2	273	0.0276	0.981	5.12	1.0E-5	0.9994	0.0005	5.82	317.7	1.1E-5	2.6E+7	0.0122	0	24	68			
3	0	0.1525	0	706.7	278	0.0312	0.979	5.79	1.0E-5	0.9993	0.0006	6.58	281.0	1.1E-5	2.6E+7	0.0122	0	21	72			
4	0	0.1525	0	799.7	283	0.0348	0.977	6.46	1.1E-5	0.9993	0.0007	7.33	252.1	1.1E-5	2.5E+7	0.0122	0	19	57			
5	0	0.1525	0	875.0	286	0.0377	0.976	6.99	1.1E-5	0.9992	0.0007	7.94	232.8	1.2E-5	2.4E+7	0.0122	0	17	37			
6	0	0.1525	0	929.4	288	0.0398	0.975	7.38	1.1E-5	0.9991	0.0008	8.38	220.4	1.2E-5	2.4E+7	0.0122	0	33	23			
8	0	0.1525	0	985.5	289	0.0420	0.974	7.81	1.1E-5	0.9991	0.0008	8.86	208.5	1.2E-5	2.4E+7	0.0122	0	31	23			
10	0	0.1525	0	1039.1	290	0.0442	0.973	8.21	1.1E-5	0.9990	0.0009	9.32	198.3	1.2E-5	2.4E+7	0.0122	0	73	19	Eros	Time To	
15	0	0.1525	0	1132.0	291	0.0481	0.971	8.94	1.1E-5	0.9990	0.0010	10.15	182.2	1.2E-5	2.4E+7	0.0122	0	68	31	Rate	Failure	
20	0	0.1525	0	1230.7	292	0.0522	0.969	9.69	1.1E-5	0.9989	0.0010	11.00	167.9	1.2E-5	2.3E+7	0.0122	0	62	27	(m/s)	(s)	(min)
25	0	0.1525	0	1320.3	293	0.0559	0.967	10.38	1.1E-5	0.9988	0.0011	11.79	156.8	1.2E-5	2.3E+7	0.0122	0	58	21			
25.46	0	0.1525	0	1399.7	294	0.0592	0.965	11.00	1.1E-5	0.9987	0.0012	12.48	148.0	1.2E-5	2.3E+7	0.0122	0	50	17	7E-06	1398	23.3
30	0	0.1525	0	1399.7	294	0.0592	0.965	11.00	1.1E-5	0.9987	0.0012	12.48	148.0	1.2E-5	2.3E+7	0.0122	0	0	17			
30	0	0.711	0.127	1416.4	295	0.0598	0.965	11.11	1.1E-5	0.9987	0.0012	12.61	7.0	1.2E-5	4.1E+6	0.0105	0	0	138	Over	Pore	Min
30	0	0.711	0.127	1554.3	299	0.0648	0.963	12.03	1.1E-5	0.9986	0.0013	13.65	6.4	1.3E-5	4.0E+6	0.0106	9	0	0	Bur	Pres	Frac
100	70	0.711	0.127	1564.1	299	0.0652	0.963	12.10	1.1E-5	0.9986	0.0013	13.74	6.4	1.3E-5	4.0E+6	0.0106	11	0	0	Stress		Pres
179	149	0.711	0.127	1575.1	299	0.0657	0.963	12.19	1.1E-5	0.9986	0.0013	13.84	6.3	1.3E-5	4.0E+6	0.0106	0	0	0	(kPa)	(kPa)	(kPa)
179	149	0.251	0.127	1575.1	299	0.0657	0.963	12.19	1.1E-5	0.9986	0.0013	13.84	66.3	1.3E-5	9.0E+6	0.0128	3	66	0	1807	1373	1541
200	170	0.251	0.127	1644.0	298	0.0689	0.961	12.79	1.1E-5	0.9985	0.0014	14.51	63.2	1.3E-5	8.9E+6	0.0128	8	162	3	2217	1661	1878
254	224	0.251	0.127	1816.3	298	0.0764	0.957	14.19	1.1E-5	0.9984	0.0015	16.10	57.0	1.3E-5	8.8E+6	0.0128	0	0	6	3272	2400	2753
254	224	0.251	0.191	1822.3	299	0.0766	0.957	14.23	1.1E-5	0.9984	0.0015	16.14	100.4	1.3E-5	7.5E+6	0.0148	3	421	0	3272	2400	2753
275	245	0.251	0.191	2246.4	297	0.0960	0.946	17.83	1.1E-5	0.9979	0.0019	20.22	80.2	1.3E-5	7.3E+6	0.0148	5	400	37	3684	2687	3096
300	270	0.251	0.191	2688.3	298	0.1158	0.936	21.51	1.1E-5	0.9975	0.0023	24.38	66.5	1.4E-5	7.0E+6	0.0148	6	332	24	4175	3029	3506
325	295	0.251	0.191	3050.6	298	0.1324	0.928	24.59	1.2E-5	0.9972	0.0026	27.86	58.2	1.4E-5	6.8E+6	0.0148	8	325	14	4667	3371	3919
353	323	0.251	0.191	3398.0	298	0.1486	0.920	27.61	1.2E-5	0.9968	0.0030	31.27	51.8	1.5E-5	6.6E+6	0.0148	0	10	11	5220	3754	4383
354	324	0.251	0.222	3419.6	299	0.1496	0.919	27.78	1.2E-5	0.9968	0.0030	31.47	99.6	1.5E-5	6.1E+6	0.0173	0	0	0	5239	3768	4400
354	324	0.251	0	3419.6	297	0.1506	0.918	27.96	1.2E-5	0.9968	0.0030	31.67	21.5	1.5E-5	1.2E+7	0.0113	2	2	150	5239	3768	4400
360	330	0.251	0	3573.1	299	0.1566	0.916	29.08	1.2E-5	0.9966	0.0031	32.93	20.7	1.5E-5	1.1E+7	0.0113	3	3	1	5358	3850	4500
370	340	0.251	0	3580.1	299	0.1569	0.916	29.14	1.2E-5	0.9966	0.0031	33.00	20.7	1.5E-5	1.1E+7	0.0113	4	3	0	5556	3987	4667
381	351	0.251	0	3587.2	299	0.1572	0.916	29.20	1.2E-5	0.9966	0.0031	33.07	20.6	1.5E-5	1.1E+7	0.0113	0	0	0	5773	4137	4851
381	351			3587.2																		
	Imbalance			0																		

Table 4 -- Page 1 of Example Spreadsheet for 10-in. diameter Diverter

WELL CONDITIONS OF CALCULATION:

Diameter	0.254	m	10.000 in.
Pipe Roughness	1.7E-5	m	6.5E-4 in.
Base Pressure	101.3	kPa	14.69 psi
Base Temperature	15	Deg C	59 Deg F
Exit Temperature	-5	Deg C	23 Deg F
Liquid Content	0.1	Wt Frac	15 Bbl/MMscf
Density of Liquids	1060	kg/m3	8.85 lb/gal
Liquid Compressibility	4.7E-7	kPa-1	3.3E-6 psi-1
Liquid Heat Capacity	4.2	kJ/kg/Deg K	1.00 btu/lb/Deg R
Solid Content	0.02	Wt Frac	1112 lb/MMscf
Density of Solids	2630	kg/m3	21.95 lb/gal
Solid Compressibility	4.0E-8	kPa-1	2.8E-7 psi-1
Solid Heat Capacity	0.9	kJ/kg/Deg K	0.21 btu/lb/Deg R
Viscosity of Liquid-Solid Mixture	1.0E-3	Pa.s	1.00 cp
Gas Specific Gravity	0.64		0.64
Heat Capacity Ratio, k	1.31		1.31
Gas Quality	0.88	Wt Frac	0.88 Wt Frac
M	18.5	kg/mole	18.5 lb/mole
Universal Gas Constant, R	8.31	kJ/kmole/Deg	1.99 btu/mole/Deg R
Gas Constant (mass basis), R'	0.448	kJ/kg/DegK	10.73 psi ft3/Deg R/mole
Cp	2.21	kJ/kg/Deg K	0.53 btu/lb/Deg R
Cv	1.69	kJ/kg/Deg K	0.40 btu/lb/Deg R

FORMATION CHARACTERISTICS:

Formation Pressure	4137	kPa	600 psi
Formation Temp	30	Deg C	86 Deg F
Permeability	1.5E-11	m2	1.5E+4 md
Non-Darcy Beta	3.3E+5	m-1	1.0E+5 ft-1
Skin Factor	0		0
Reservoir Radius	305	m	1001 ft
Wellbore Radius	0.126	m	0.41 ft
Formation Eff. Thick	3.05	m	10 ft
Formation Depth	351	m	1152 ft
Water Depth	58.0	m	190 ft
Air Gap	33.0	m	108 ft
Porosity Decline Con	2.8E-4	m-1	8.5E-5 ft-1
Specific Erosion Factor	6.6E-4	kg/kg	6.6E-4 lb/lb
Wall Thickness	0.0095	m	0.375 in.
Wall Density	7850	Kg/m3	65.51 lb/gal
Tr at Formation	1.48		1.48
Pseudo Reduced Densi	0.181		0.18
Formation Gas z Factor	0.908		0.91
Formation Gas Density	100	kg/m3	0.83 lb/gal
Formation Gas Viscosit	1.5E-5	Pa.s	0.015 cp

Diverter Exit Calculations

(1) Pres (kPa)	(psi)	Pseudo Reduced Density	(2) z	(3) Gas Den Eqn. 2 (kg/m3)	(4) n Eqn. 6	(5) Cg Eqn. 3 (kPa-1)	(6) Gas Vol Frac	Liquid Vol Frac	Solids Vol Frac	(7) Mix Density Eqn. 4 (kg/m3)	(8) Mix Comp. Eqn. 5 (Pa-1)	(10) Gas Flow Rate at S.C. (m3/s)	(MM/d)	(11) Flowing BH Pressure at formation (kPa)	(psi)
187.28	27.2	0.0084	0.994	1.57	1.42	3.8E-3	0.9998	0.0002	0.0000	1.78	3.8E-3	39.2	119.5	3560	516

Table 5 --Page 2 of Example Spreadsheet for 10-in. Diverter

Flow Path Pressure Drop Calculations

(1) Dist From Exit (m)	Vert Depth (m)	(2) Outer Pipe Diam (m)	Inner Pipe Diam (m)	(3) Pres (kPa)	(4) Temp (oK)	(5) Pseudo Red Den	(6) z	(7) Gas Den Eqn. 2 (kg/m3)	(8) Gas Visc (Pa-s)	(9) Gas Vol Frac	Liq Vol Frac	(10) Mix Den Eqn. 4 (kg/m3)	(11) Mix Vel (m/s)	(12) Mix Visc (Pa-s)	(13) Rey Num	(14) Moody Fric Fac	(15) Hyd dP (kPa)	(16) Fric dP (kPa)	(17) Acc dP (kPa)	(18)	(19)	(20)
0	0	0.254	0	187.3	268	0.0084	0.994	1.57	9.9E-6	0.9998	0.0002	1.78	386.6	1.0E-5	1.7E+7	0.0112	0	3	0			
0.5	0	0.254	0	190.2	268	0.0086	0.994	1.59	9.9E-6	0.9998	0.0002	1.81	380.6	1.0E-5	1.7E+7	0.0112	0	3	4			
1	0	0.254	0	197.3	269	0.0089	0.993	1.65	1.0E-5	0.9998	0.0002	1.87	368.3	1.0E-5	1.7E+7	0.0112	0	6	9			
2	0	0.254	0	211.5	271	0.0094	0.993	1.75	1.0E-5	0.9998	0.0002	1.99	345.9	1.0E-5	1.7E+7	0.0112	0	5	16			
3	0	0.254	0	232.7	274	0.0103	0.993	1.90	1.0E-5	0.9998	0.0002	2.16	318.1	1.0E-5	1.7E+7	0.0112	0	5	20			
4	0	0.254	0	257.5	278	0.0112	0.992	2.08	1.0E-5	0.9998	0.0002	2.36	291.5	1.1E-5	1.7E+7	0.0112	0	4	19			
5	0	0.254	0	281.1	282	0.0121	0.992	2.24	1.0E-5	0.9997	0.0002	2.55	270.2	1.1E-5	1.6E+7	0.0112	0	4	15			
6	0	0.254	0	300.4	284	0.0128	0.992	2.38	1.1E-5	0.9997	0.0003	2.70	254.9	1.1E-5	1.6E+7	0.0112	0	8	11			
8	0	0.254	0	319.0	286	0.0135	0.991	2.51	1.1E-5	0.9997	0.0003	2.85	241.4	1.1E-5	1.6E+7	0.0112	0	7	10			
10	0	0.254	0	335.9	287	0.0142	0.991	2.63	1.1E-5	0.9997	0.0003	2.99	230.3	1.1E-5	1.6E+7	0.0112	0	18	8	Eros	Time To	
15	0	0.254	0	361.2	288	0.0152	0.990	2.82	1.1E-5	0.9997	0.0003	3.20	214.9	1.1E-5	1.6E+7	0.0112	0	16	11	Rate	Failure	
20	0	0.254	0	388.6	290	0.0163	0.990	3.02	1.1E-5	0.9997	0.0003	3.43	200.7	1.1E-5	1.6E+7	0.0112	0	15	10	(m/s)	(s)	(min)
25	0	0.254	0	414.0	291	0.0173	0.989	3.21	1.1E-5	0.9996	0.0003	3.64	189.0	1.1E-5	1.6E+7	0.0112	0	14	8			
25.46	0	0.254	0	436.6	292	0.0182	0.989	3.37	1.1E-5	0.9996	0.0004	3.83	179.8	1.1E-5	1.6E+7	0.0112	0	12	7	4E-06	2546	42.4
30	0	0.254	0	436.6	292	0.0182	0.989	3.37	1.1E-5	0.9996	0.0004	3.83	179.8	1.1E-5	1.6E+7	0.0112	0	0	7			
30	0	0.711	0.127	443.2	293	0.0184	0.989	3.41	1.1E-5	0.9996	0.0004	3.88	23.4	1.1E-5	4.7E+6	0.0105	0	0	62	Over	Pore	Min
30	0	0.711	0.127	504.8	299	0.0205	0.988	3.80	1.1E-5	0.9996	0.0004	4.32	21.0	1.2E-5	4.6E+6	0.0105	3	1	0	Bur	Pres	Frac
100	70	0.711	0.127	509.1	299	0.0207	0.988	3.84	1.1E-5	0.9996	0.0004	4.36	20.8	1.2E-5	4.6E+6	0.0105	3	1	0	Stress		Pres
179	149	0.711	0.127	513.9	299	0.0209	0.988	3.87	1.1E-5	0.9996	0.0004	4.40	20.6	1.2E-5	4.6E+6	0.0105	0	0	0	(kPa)	(kPa)	(kPa)
179	149	0.251	0.127	513.9	299	0.0209	0.988	3.87	1.1E-5	0.9996	0.0004	4.40	215.3	1.2E-5	1.0E+7	0.0128	1	221	0	1807	1373	1541
200	170	0.251	0.127	736.0	290	0.0311	0.981	5.78	1.1E-5	0.9993	0.0006	6.56	144.5	1.1E-5	1.0E+7	0.0128	3	382	84	2217	1661	1878
254	224	0.251	0.127	1204.8	295	0.0505	0.970	9.38	1.1E-5	0.9989	0.0010	10.65	89.0	1.2E-5	9.7E+6	0.0128	0	0	69	3272	2400	2753
254	224	0.251	0.191	1273.8	298	0.0530	0.970	9.84	1.1E-5	0.9989	0.0011	11.17	150.0	1.2E-5	8.1E+6	0.0148	2	649	0	3272	2400	2753
275	245	0.251	0.191	1925.3	295	0.0824	0.952	15.29	1.1E-5	0.9982	0.0016	17.35	96.5	1.3E-5	7.8E+6	0.0148	4	498	114	3684	2687	3096
300	270	0.251	0.191	2541.5	298	0.1092	0.939	20.28	1.1E-5	0.9977	0.0022	23.00	72.8	1.4E-5	7.3E+6	0.0148	6	376	46	4175	3029	3506
325	295	0.251	0.191	2968.9	298	0.1285	0.930	23.87	1.2E-5	0.9972	0.0026	27.05	61.9	1.4E-5	7.0E+6	0.0148	7	358	20	4667	3371	3919
353	323	0.251	0.191	3353.9	299	0.1464	0.921	27.19	1.2E-5	0.9969	0.0029	30.80	54.4	1.5E-5	6.8E+6	0.0148	0	11	14	5220	3754	4383
354	324	0.251	0.222	3379.0	299	0.1475	0.920	27.39	1.2E-5	0.9968	0.0029	31.03	104.4	1.5E-5	6.3E+6	0.0173	0	0	0	5239	3768	4400
354	324	0.251	0	3379.0	297	0.1486	0.919	27.59	1.2E-5	0.9968	0.0029	31.25	22.6	1.5E-5	1.2E+7	0.0113	2	2	162	5239	3768	4400
360	330	0.251	0	3545.2	299	0.1550	0.917	28.79	1.2E-5	0.9967	0.0031	32.61	21.6	1.5E-5	1.2E+7	0.0113	3	3	1	5358	3850	4500
370	340	0.251	0	3552.5	299	0.1554	0.917	28.86	1.2E-5	0.9967	0.0031	32.68	21.6	1.5E-5	1.2E+7	0.0113	4	4	0	5556	3987	4667
381	351	0.251	0	3559.9	299	0.1557	0.917	28.92	1.2E-5	0.9967	0.0031	32.76	21.5	1.5E-5	1.2E+7	0.0113	0	0	0	5773	4137	4851
381	351			3559.9																		
		Imbalance		0																		